

at approximately the original reservoir pressure or approximately the original bubble point pressure. Likewise for deep saline aquifers the pore space is saturated by water at original reservoir pressure if the gas was produced under active water drive.

By far the best prospect among these choices for bulk carbon dioxide injection is an abandoned oil reservoir. However, typically such reservoirs are used for natural gas storage and would not be liquid saturated prospects, oil reservoirs abandoned at lower than initial pressure will be abandoned after waterflood or deep saline aquifers. The following discussion provides a case for an aquifer, and with minor adjustments this would apply to any liquid filled underground reservoir.

There are two considerations: the wellbore pressure increase over average reservoir pressure over the initial reservoir pressure. For a deep saline aquifer, the initial formation pressure is $0.433H$, where H is the aquifer depth in ft. The formation temperature will be a function of the order of 1°F per 100 ft. With a critical pressure of 1071 psi and critical temperature of 311°F , bottomhole injection conditions for aquifer depths exceeding 2473 ft. This is preferred because, therefore, enables storage of more mass per unit underground pore volume.

At first, the bottomhole pressure during CO_2 injection at a constant rate is governed by the following equation:

$$p_{wi} = p_i - \frac{70.6(-q_{\text{CO}_2})\mu_w}{kh} \ln \left(\frac{kt}{1688\phi\mu_{ci}r_w^2} \right) \quad (1)$$

where the downhole injection rate is shown as $-q_{\text{CO}_2}$ in bpd; wellbore injection and initial reservoir pressures are p_{wi} and p_i , both in psi; t in hours, k and ϕ are the aquifer absolute permeability in md and porosity; r_w is the well radius in ft; μ_w is the brine viscosity, and c_{ii} is the initial total compressibility in psi^{-1} accounting for brine and rock compressibility at initial injection conditions. During this early injection period, the injection rate may be ramped up gradually to avoid injecting at a pressure above the formation fracture pressure, p_f , which depends on the formation fracture gradient, which for almost all reservoirs will range from 0.71 to 0.82 psi/ft (Economides and Nolte, 2000). After a relatively short period, typically lasting from a few days to a few months, the bulk carbon dioxide injection establishes a zone near the well in which CO_2 flows as a single phase zone surrounded by a two-phase region where the saturation varies from nearly 100% CO_2 to 100% brine according to Buckley and Leverett (1942) displacement theory. Burton et al. (2008) provide equations for the radii of the single phase and two-phase zones and the pressure drop across each of these zones as well as the pressure drop in the single phase brine.

For this study, the pressure increase over average reservoir pressure is given by

$$p_{wi} = \bar{p} - \frac{141.2(-q_{\text{CO}_2})}{kh} \left[\frac{\mu_{\text{CO}_2}}{k_{r,\text{CO}_2}=1} \ln \left(\frac{r_{\text{dry}}}{r_w} \right) + \left(\frac{k_{\text{CO}_2}}{k_{\text{CO}_2}} + \frac{k_{rw}}{\mu_w} \right)^{-1} \right]_{S_{\text{CO}_2,\text{avg}}} \ln \left(\frac{r_{\text{BL}}}{r_{\text{dry}}} \right) + \mu_w \ln \left(\frac{0.472r_e}{r_{\text{BL}}} \right) \quad (2)$$

where CO_2 and water viscosities are μ_{CO_2} and μ_w in cp; relative permeabilities are k_{CO_2} and k_{rw} ; and outer radii of the single phase CO_2 , 2-phase Buckley-Leverett, and single phase brine are r_{dry} , r_{BL} , and r_e . The relative permeability of the CO_2 in the single phase region is $k_{r,\text{CO}_2}=1$, and relative permeability values in the 2-phase region are evaluated at the average CO_2 saturation according to Buckley-Leverett displacement theory. The factor 0.472 in the last natural logarithm term in Eq. (2) accounts for average reservoir pressure, \bar{p} , as the average pressure in the brine region and is a departure from the Burton et al. (2008) approach, which claimed, incorrectly, that treating the aquifer as open, with a constant pressure outer boundary, was equivalent to modeling an effectively infinite aquifer.

Eq. (2) assumes the aquifer volume is limited and that pseudo-steady state flow behavior is established. The open aquifer, or steady state, flow condition assumes that at some distance, pressure in the aquifer is held at a constant value. For this to be true in practice, the aquifer must either outcrop to the land surface or in a stream, lake, or ocean bed where it would be in equilibrium either with atmospheric pressure or with the pressure at the stream, lake or ocean bottom. An outcropping aquifer would provide a potential path for injected CO_2 to escape back to the atmosphere, thereby defeating the purpose of CO_2 sequestration.

The consequence of assuming the aquifer has a limited area is that the average aquifer pressure will increase over time. Thus, accounting for material balance,

$$(\bar{p} - p_i)V_r c_t = V_{\text{CO}_2} \quad (3)$$

where V_{CO_2} is the total volume of CO_2 to be injected over the life of the sequestration project, V_r is the minimum required aquifer pore volume to store this volume of CO_2 , and c_t is the total compressibility accounting for CO_2 , brine, and rock compressibility as

$$c_t = \frac{[(r_{\text{dry}}^2 - r_w^2)c_{\text{CO}_2} + (r_{\text{dry}}^2 - r_{\text{BL}}^2)[S_{\text{CO}_2,\text{avg}}c_{\text{CO}_2} + (1 - S_{\text{CO}_2,\text{avg}})] + (r_e^2 - r_{\text{BL}}^2)c_w}{(r_e^2 - r_w^2)} + c_r \quad (4)$$

using a bulk volume weighted average.

Finally, the difference between the wellbore injection pressure and the initial reservoir pressure will be

$$p_{wi} - p_i = p_{wi} - \bar{p} + \bar{p} - p_i = - \frac{141.2(q_{\text{CO}_2})}{kh} \left[\frac{\mu_{\text{CO}_2}}{k_{r,\text{CO}_2}=1} \ln \left(\frac{r_{\text{dry}}}{r_w} \right) + \left(\frac{k_{\text{CO}_2}}{k_{\text{CO}_2}} + \frac{k_{rw}}{\mu_w} \right)^{-1} \right]_{S_{\text{CO}_2,\text{avg}}} \ln \left(\frac{r_{\text{BL}}}{r_{\text{dry}}} \right) + \mu_w \ln \left(\frac{0.472r_e}{r_{\text{BL}}} \right) + \frac{V_{\text{CO}_2}}{V_r c_t} \quad (5)$$

Many of the published works seem to be consumed by simulating the physics and thermodynamics of CO_2 displacing brine or its dissolution in the brine (the latter is a woefully slow process), while they are missing by far the most fundamental issue: during injection sequestration is not displacement but permanent storage in a closed system. Several authors (Kumar et al., 2005; Baklid and Korbo, 1996; Pruess, 2004; Nghiem et al.,

at approximately the original reservoir pressure or approximately the original bubble point pressure. In all cases the pore space is likely to be saturated mainly by liquid. Likewise for deep saline aquifers the pore space is saturated by brine. For depleted gas reservoirs, the pore space may be saturated by gas at abandonment pressure well below the original reservoir pressure plus connate water or it may be mainly saturated by water at original reservoir pressure if the gas was produced under active water drive.

By far the best prospect among these choices for bulk carbon dioxide injection is an abandoned gas reservoir depleted without active water drive. However, typically such reservoirs are used for natural gas storage and would not be available for carbon dioxide sequestration. Of the liquid saturated prospects, oil reservoirs abandoned at lower than initial pressure will offer somewhat more storability than oil reservoirs abandoned after waterflood or deep saline aquifers. The following discussion provides a conceptual model for bulk CO₂ injection in a deep saline aquifer, and with minor adjustments this would apply to any liquid filled underground reservoir, including depleted oil and gas reservoirs.

There are two considerations: the wellbore pressure increase over average reservoir pressure, and the increase in average reservoir pressure over the initial reservoir pressure. For a deep saline aquifer, the initial formation pressure in psi is likely to be hydrostatic and therefore equal to 0.433H, where H is the aquifer depth in ft. The formation temperature will be a function of the geothermal gradient, which on average may be on the order of 1 °F per 100 ft. With a critical pressure of 1071 psi and critical temperature of 87.8 °F, CO₂ will be in a supercritical state at bottomhole injection conditions for aquifer depths exceeding 2473 ft. This is preferred because supercritical CO₂ is denser than gaseous CO₂ and, therefore, enables storage of more mass per unit underground pore volume.

At first, the bottomhole pressure during CO₂ injection at a constant rate is governed by transient flow of single phase brine given by the following equation:

$$p_{wi} = p_i - \frac{70.6(-q_{CO_2})\mu_w}{kh} \ln\left(\frac{kt}{1688\phi\mu_{ci}r_w^2}\right) \quad (1)$$

where the downhole injection rate is shown as $-q_{CO_2}$ in bpd; wellbore injection and initial reservoir pressures are p_{wi} and p_i , both in psi; t in hours, k and ϕ are the aquifer absolute permeability in md and porosity; r_w is the well radius in ft; μ_w is the brine viscosity, and c_{ti} is the initial total compressibility in psi⁻¹ accounting for brine and rock compressibility at initial injection conditions. During this early injection period, the injection rate may be ramped up gradually to avoid injecting at a pressure above the formation fracture pressure, p_f , which depends on the formation fracture gradient, which for almost all reservoirs will range from 0.71 to 0.82 psi/ft (Economides and Nolte, 2000). After a relatively short period, typically lasting from a few days to a few months, the bulk carbon dioxide injection establishes a zone near the well in which CO₂ flows as a single phase zone surrounded by a two-phase region where the saturation varies from nearly 100% CO₂ to 100% brine according to Buckley and Leverett (1942) displacement theory. Burton et al. (2008) provide equations for the radii of the single phase and two-phase zones and the pressure drop across each of these zones as well as the pressure drop in the single phase brine.

For this study, the pressure increase over average reservoir pressure is given by

$$p_{wi} = \bar{p} - \frac{141.2(-q_{CO_2})}{kh} \left[\frac{\mu_{CO_2}}{k_{r,CO_2}=1} \ln\left(\frac{r_{dry}}{r_w}\right) + \left(\frac{k_{CO_2}}{\mu_{CO_2}} + \frac{k_{rw}}{\mu_w}\right)^{-1} \right]_{S_{CO_2,avg}} \ln\left(\frac{r_{BL}}{r_{dry}}\right) + \mu_w \ln\left(\frac{0.472r_e}{r_{BL}}\right) \quad (2)$$

where CO₂ and water viscosities are μ_{CO_2} and μ_w in cp; relative permeabilities are k_{CO_2} and k_{rw} ; and outer radii of the single phase CO₂, 2-phase Buckley–Leverett, and single phase brine are r_{dry} , r_{BL} , and r_e . The relative permeability of the CO₂ in the single phase region is $k_{r,CO_2}=1$, and relative permeability values in the 2-phase region are evaluated at the average CO₂ saturation according to Buckley–Leverett displacement theory. The factor 0.472 in the last natural logarithm term in Eq. (2) accounts for average reservoir pressure, \bar{p} , as the average pressure in the brine region and is a departure from the Burton et al. (2008) approach, which claimed, incorrectly, that treating the aquifer as open, with a constant pressure outer boundary, was equivalent to modeling an effectively infinite aquifer.

Eq. (2) assumes the aquifer volume is limited and that pseudo-steady state flow behavior is established. The open aquifer, or steady state, flow condition assumes that at some distance, pressure in the aquifer is held at a constant value. For this to be true in practice, the aquifer must either outcrop to the land surface or in a stream, lake, or ocean bed where it would be in equilibrium either with atmospheric pressure or with the pressure at the stream, lake or ocean bottom. An outcropping aquifer would provide a potential path for injected CO₂ to escape back to the atmosphere, thereby defeating the purpose of CO₂ sequestration.

The consequence of assuming the aquifer has a limited area is that the average aquifer pressure will increase over time. Thus, accounting for material balance,

$$(\bar{p} - p_i)V_r c_t = V_{CO_2} \quad (3)$$

where V_{CO_2} is the total volume of CO₂ to be injected over the life of the sequestration project, V_r is the minimum required aquifer pore volume to store this volume of CO₂, and c_t is the total compressibility accounting for CO₂, brine, and rock compressibility as

$$c_t = \frac{[(r_{dry}^2 - r_w^2)c_{CO_2} + (r_{dry}^2 - r_{BL}^2)[S_{CO_2,avg}c_{CO_2} + (1 - S_{CO_2,avg})] + (r_e^2 - r_{BL}^2)c_w]}{(r_e^2 - r_w^2)} + c_r \quad \text{EXHIBIT NO.} \quad (4)$$

using a bulk volume weighted average.

Finally, the difference between the wellbore injection pressure and the initial reservoir pressure will be $\Delta p_{wi} = p_{wi} - p_i$ WELL NO. _____

$$p_{wi} - p_i = p_{wi} - \bar{p} + \bar{p} - p_i = - \frac{141.2(q_{CO_2})}{kh} \left[\frac{\mu_{CO_2}}{k_{r,CO_2}=1} \ln\left(\frac{r_{dry}}{r_w}\right) + \left(\frac{k_{CO_2}}{\mu_{CO_2}} + \frac{k_{rw}}{\mu_w}\right)^{-1} \right]_{S_{CO_2,avg}} \ln\left(\frac{r_{BL}}{r_{dry}}\right) + \mu_w \ln\left(\frac{0.472r_e}{r_{BL}}\right) + \frac{V_{CO_2}}{V_r c_t} \quad (5)$$

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